REVIEW OF JAMAICA PUBLIC SERVICE COMPANY, LTD LEAST-COST EXPANSION PLAN

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1 BACKGROUND

Argonne National Laboratory has been asked to review the least-cost expansion plan (LCEP) of the Jamaica Public Service Company, Ltd. (JPSCo). The material that has been initially provided to Argonne included:

- An electronic copy of the data and results from JPSCo's running the WASP electric system expansion planning model,

- Approximately 20 pages of a document *JPSCo Generation Expansion Plan*, marked "DRAFT 002", date unknown, and

- The report *JPSCo Least Cost Generation Expansion Plans, (1999-2009),* January 1999

It was noticed that the 20 pages from the "DRAFT 002" document were different from the January 1999 report. An explanation was provided to Argonne that the excerpt was from an earlier draft and that the review should focus on the January 1999 report. Further, the electronic copy of the WASP case did not correspond to either the January 1999 report or to the 20-page excerpt. Again, the reason for these discrepancies was that the WASP case provided to Argonne was an earlier case and not the final one that was presented in the report.

Based on the review of the available material, Argonne experts have prepared and submitted to the National Investment Bank of Jamaica (NIBJ) a preliminary draft report containing the initial findings, comments, questions and observations. As many of the comments and questions raised in the preliminary review needed to be discussed with the appropriate staff of JPSCo and other Jamaican experts, a 3-day mission to Jamaica was carried out by one Argonne expert (V. Koritarov) in the period July 20-23, 1999.

Besides JPSCo experts, the discussions and the review of the LCEP during the mission included several experts from NIBJ, Ministry of Energy, and the Petroleum Corporation of Jamaica. Mr. Koritarov also worked with the JPSCo technical staff to reconstruct the WASP base case that was used as a basis for the January 1999 report. The first step was to verify that the results obtained after the resimulation of this case were identical to those presented in the January 1999 report. Then, in the next step, the Argonne expert and JPSCo team reviewed this case in detail and performed certain modifications and improvements of data where necessary. These modifications and data adjustments resulted in a new base case that served as a basis for further review and for the sensitivity analyses. Several sensitivity analyses were performed together with JPSCo experts and the results were discussed with the JPSCo management and other Jamaican experts at the end of the mission. Additional sensitivity analyses, as well as the cases for high and low load forecasts, were conducted by Mr. Koritarov after returning from Jamaica. The main findings of the review and issues that have been discussed with the Jamaican team can be summarized as follows.

2 MAIN FINDINGS AND COMMENTS

2.1 DEMAND FORECAST

- JPSCo has developed load forecasts for three growth scenarios: base, low, and high. The average annual load growth over the period 1998-2017 was projected at 6.15% for the base case, at 3.46% for the low-growth scenario, and at 8.37% for the high-growth scenario. These projections were developed using an econometric model that takes into account several variables such as projections of GDP, disposable income per capita, employment, exchange rate, and the growth of urban population. The obtained results seem to be reasonable and the three growth projections cover a relatively wide range of possible future demand growth.

- While the use of an econometric model and a regression analysis of electricity demand with explanatory variables (as referenced on p 11 of the January 1999 document) is a generally accepted load forecasting technique, it does not account for significant changes in the structure of demand. The statement on the bottom of p 4 of the January 1999 document illustrates this point when commenting on a step change in demand due to the addition of the Caribbean Cement Co. facility. A preferred methodology for load forecasting is one that combines techniques to address significant structural changes in demand (such as major new facilities, changes in consumer behavior, etc.) with conventional techniques of analyzing historical trends in demand.

- The input system load factor (p 4 of the January 1999 report) is projected to remain at 72% over the time horizon (71% in the WASP case data). This is a rather high system load factor that may decrease with the expansion of the system in the future, especially if there are no active demand side management programs in place. The January 1999 report (p 12) mentions demand side management but only in the context of pilot programs. At present, it is not clear if these DSM programs will be fully implemented and what their contribution will be to the reduction of system loads and if they will be sufficient to maintain the high system load factor.

- Although three demand forecasts (base, high, and low) are shown in the report (Table 1, p 4 of the January 1999 report), the results presented in the report are related only to the base load forecast, and no results are shown for the analyses performed using the high and low load forecasts. Argonne suggests that the results obtained for other load forecasts, as well as for the sensitivity studies be presented, thus providing a comprehensive report covering all aspects of the planning process.

2.2 FUEL PRICE FORECAST

- Except for a short discussion on p 21, the January 1999 document does not provide much information on the projections of fuel prices that were used in the LCEP analysis. Instead, the assumed projections of fuel prices were obtained directly from the WASP case, by reviewing the escalation factors for fuel prices that were used in the analysis. It was noticed that the escalation factors for diesel oil were much higher than those used for the heavy fuel oil. JPSCo experts recognized this as an error which was probably caused by using escalation factors for diesel oil that included local taxes and duties. This error was corrected for the new base case.

- The projections of fuel prices over the study period were reviewed in detail and compared to the latest projections available in the publication "International Energy Outlook 1999 with Projections to 2020," published by the Energy Information Administration of the United States Department of Energy [DOE/EIA-0484(99)], April 1999. The EIA publication presents their own projections of energy prices (for three scenarios: reference case, high price case, and low price case), as well as forecasts developed by a number of U.S. and international institutions and organizations dealing with energy. In addition, for the purpose of LCEP review, other sources that provide long-term projections of fuel prices have been consulted (e.g., The World Bank, British Petrol, etc.). The review concluded that the projections of fuel prices that were used for the LCEP analysis were closely following the general trends of projections obtained from the above sources. Based on the review of different projections, the expected market trends for major fuels can be summarized as follows. Oil prices are expected to quickly rebound from the low level experienced in 1998 to about 20 U.S.$/bbl and then to remain constant or have a slight positive escalation thereafter. Coal prices are expected to continue to decline with a negative escalation rate of about 1.5% per year. Natural gas prices are expected to have a small positive escalation rate of 0.8% per year, however natural gas is not currently a viable fuel supply option in Jamaica. For comparison, the projections of fuel prices that were used in the analysis of the new base case are illustrated in Figure 1.

- The LCEP authors have considered possibilities for fuel diversification (p 10 of the January 1999 report). This is a legitimate consideration, especially in the case of high dependency on certain types of fuel for a country's energy needs, such as Jamaica.

2.3 EXISTING SYSTEM DATA

- The existing hydro plants and most candidates are all shown as run-of-the-river with no storage capability whatsoever. If there were only a few hours of storage available at some of the hydro sites, the hydro representation in the WASP model would change considerably. This issue has been discussed with JPSCo experts who confirmed that all existing hydro power plants are purely run-of-the-river type without any regulating capability.

- In the FIXSYS module of WASP, the forced outage rates for generating units were mostly specified as 6% and for some units as 5%. Forced outage rates of only 5-6% for thermal plants are lower than expected and imply an active preventive maintenance program. The existence of such a maintenance program has been confirmed in discussions with JPSCo experts, so that no changes in the specification of forced outage rates for existing units were performed for the new base case analysis.

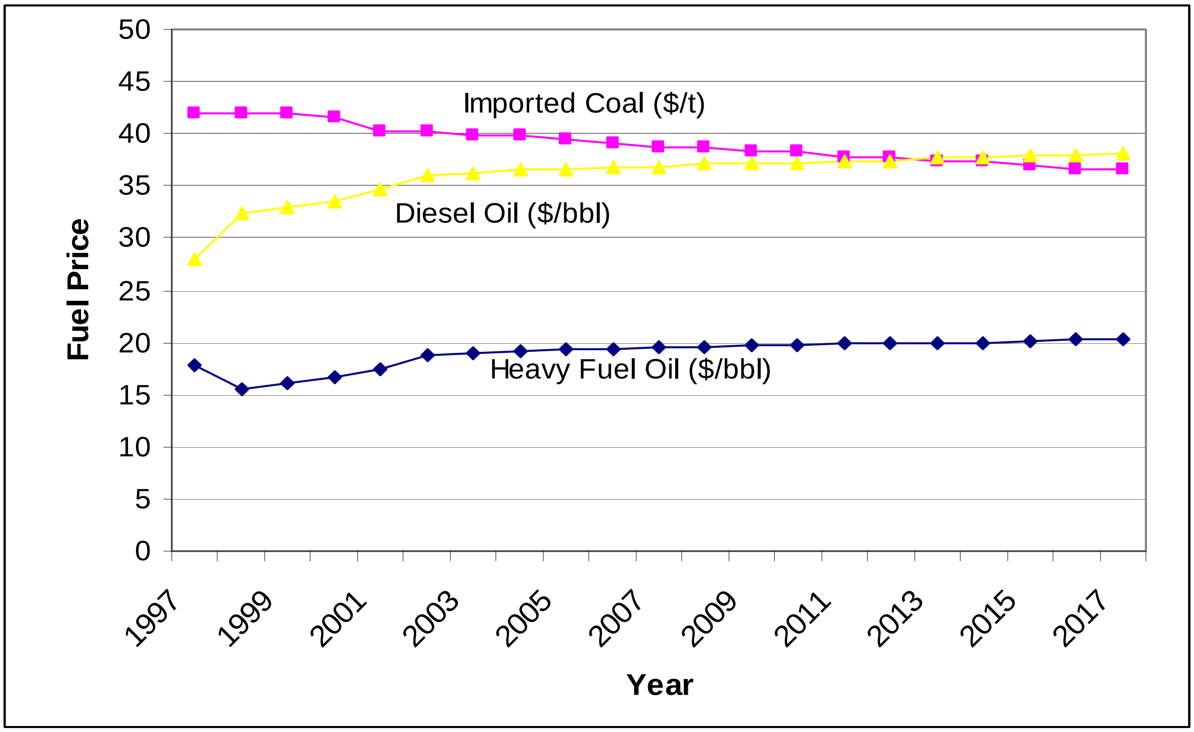

Figure 1: Projections of Fuel Prices

- The modeling of independent power producers (IPPs) was also reviewed. It was concluded that generating units owned and operated by private companies (JPPC, JEP, etc.) were modeled properly and accurately.

2.4 EXPANSION OPTIONS

- A rule of thumb from a system reliability perspective is that no generating unit should have a capacity greater than 10% of the peak load. The 120 MW units proposed for addition to the system are more than 20% of the peak in 2002. They remain more than 10% of the peak load beyond the year 2007. (The issue is addressed on p. 16 of the January 1999 report). Apparently, the decreased system reliability associated with the larger unit size is overcome by the factors listed on p. 16. However, the assumed forced outage rate of only 3% for a 120 MW coal-fired generating unit is very low and is a major factor in this reliability-cost tradeoff associated with unit size. This low forced outage rate may make the 120 MW unit (comprising more than 20% of the system peak load) unrealistically attractive. This issue has been extensively discussed with the JPSCo experts who agreed to increase the forced outage rate for coal-fired units to 8% for the new base case analysis.

- Forced outage rates for other candidate plants (WASP data) were also specified rather low (in the range from 3% to 5%). For the new base case analysis, the forced outage rates of candidate units were increased (except for the gas turbine) and specified as shown in Table 1.

Table 1: Forced Outage Rates of Candidate Units

Candidate Technology	Forced Outage Rate (%)
Oil-fired steam (63 MW)	6
Coal-fired steam (80 MW)	8
Coal-fired steam (120 MW)	8
Medium-speed diesel (20 MW)	5
Low-speed diesel (30 MW)	5
Gas (combustion) turbine (33 MW)	5
Combined-cycle (102 MW)	7

- The fuel price for coal-fired candidates was specified as U.S.$47.89 per ton of coal in the base year (1997) of the WASP case, which was deemed rather high. Currently, coal for electric power utilities on the international market is widely available at prices lower than U.S.$40 per ton. For the new base case analysis, the price of coal was reduced to U.S.$42 per ton (in the base year 1997), which also takes into account the transportation costs to Jamaica. The price of coal further decreases over the study period because of the negative escalation factors applied to the coal fuel. The price level in 2002 is about U.S.$40 per ton of coal.

- The capital investment costs for candidate units have also been carefully reviewed. The net overnight costs for the gas (combustion) turbines and combined cycle units were decreased, while the capital costs for the 120 MW coal-fired unit were increased by 15% to account for environmental control equipment. Also, interest during construction costs were added to the capital investment costs, as required by the WASP methodology. The revised net overnight costs for candidate units (in U.S. dollars as of 1997) are presented in Table 2.

- A new set of screening curves for candidate technologies was constructed to perform a preliminary assessment of the effects of changes introduced into the new base case on the expansion candidates. By plotting the levelized cost of electricity production of candidate technologies as a function of their annual utilization (or capacity factor of generating units), the screening curves provide an indication of their competitiveness for system expansion. Of course, the actual optimization of the system development with the WASP model is much more complex and takes into account many different aspects not addressed by the relatively simplistic screening curve approach. Nevertheless, the screening curve analysis is very useful, especially in the preparation phase for the systems planning exercise, and helps detect certain data inconsistencies and illustrate relative merits of candidate technologies. Figure 2 shows screening curves constructed for the expansion candidates in the new base case analysis.

Table 2: Capital Costs of Candidate Units

Candidate Technology	Net Overnight Cost (U.S.$/kW)
Oil-fired steam (63 MW)	1,200
Coal-fired steam (80 MW)	1,700
Coal-fired steam (120 MW)	1,495
Medium-speed diesel (20 MW)	1,150
Low-speed diesel (30 MW)	1,600
Gas (combustion) turbine (33 MW)	600
Combined-cycle (102 MW)	750

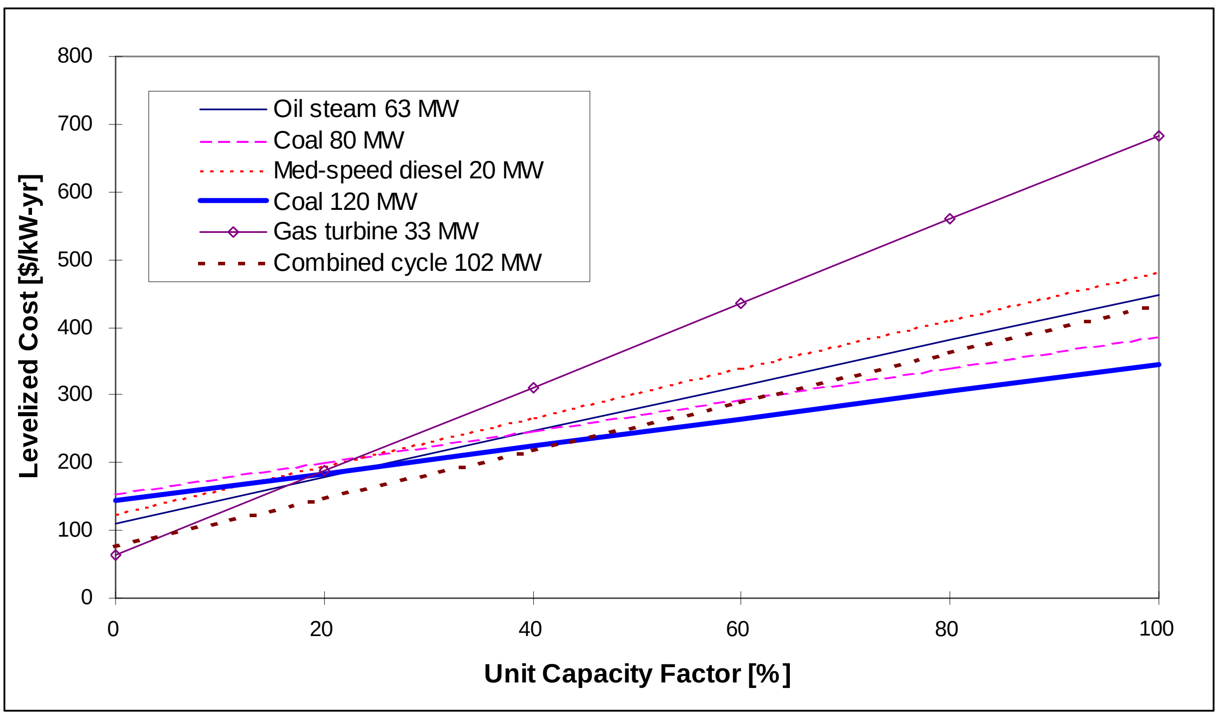

Figure 2: Screening Curves for Candidate Technologies

2.5 PLANNING VARIABLES

- The January 1999 report states that economic indicators and planning variables were obtained from the Planning Institute of Jamaica. The real discount rate used in the WASP analysis for capital investment and operating costs was 12%, which seems reasonable for a developing country such as Jamaica. The report does not provide information if sensitivity studies on lower and higher values of discount rate have been performed. These sensitivity studies should be performed, at least, for discount rates of 8, 10, and 14%.

- The value of energy-not-served (ENS) of 1.5 U.S. dollar/kWh used in the WASP analysis is within the usual range from 0.5 to 1.5 $/kWh that is commonly used for system planning purposes. However, sensitivity studies should be performed for other values of ENS, especially because the selected ENS value for the baseline analysis is at the high end of the range.

2.6 CONSTRAINTS

- The maximum value of Loss-of-load probability (LOLP) reliability parameter of 0.55% (2 days per year) used in the WASP analysis seems to be reasonable for the existing and planned plant mix in the electric power system of Jamaica.

- The maximum reserve margin in the WASP case was specified as 90% above the peak load. For the new base case analysis the maximum reserve margin was reduced to 60%. This was considered sufficient, on one hand, to include all possible system configurations that could satisfy the demand with the desired reliability and, on the other hand, to avoid examining a large number of configurations with significant excess capacity.

2.7 OPTIMIZATION RESULTS

- The results obtained for the new base case and sensitivity studies are presented in Table 3. The total cost of the least-cost expansion plan obtained for the base case analysis, which represents a present worth (expressed in U.S. dollars as of 1997) of all system investment and operating costs over the study period 1997-2017, amounted to U.S.$ 1.952 billion. For the purpose of sensitivity analysis, the optimization of system development was also performed for a number of different scenarios. The costs of these alternative scenarios are also presented in Table 3, as well as the cost difference of each alternative scenario compared to the base case analysis.

Table 3: Optimization Results for the New Base Case and Sensitivity Studies

	Expansion Scenario	PW(1997) Cost of Plan (US$ 000)	PW(1997) Difference (US$ 000)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL (MW)
Base Load Forecast	Base Case (Coal Avail. 2002)	1951975	0	-	-	GT 33	C 120	-	GT 33	C 120	-	GT 33	C 120	CC 102	561
	No Coal until 2003	1952432	457	-	-	GT 33	GT 33	C 120	-	C 120	-	GT 33	C 120	CC 102	561
	No Coal until 2004	1954136	2161	-	-	GT 33	GT 33	GT 33	C 120	-	C 120	-	C 120	CC 102	561
	No Coal Option	1980177	28202	-	-	GT 33	GT 33	CC 102	-	GT 33	CC 102	GT 33	CC 102	CC 102	540
	No GT in 2001 (See Note 2)	1950606	-1369	-	-	-	C 120	GT 33	GT 33	C 120	-	GT 33	C 120	CC 102	561
	FOR=5% for Candidates	1933808	-18167	-	-	GT 33	C 120	-	GT 33	C 120	-	GT 33	C 120	C 120	579
	Tax on Diesel Oil (40%)	1958738	6763	-	-	GT 33	C 120	-	GT 33	C 120	-	GT 33	C 120	C 120	579
	$26M Coal Infrastr. Added	1979224	27249	-	-	GT 33	GT 33	CC 102	-	GT 33	CC 102	GT 33	CC 102	CC 102	540
	10% Increase of Coal Prices	1965224	13249	-	-	GT 33	GT 33	C 120	-	GT 33	C 120	-	C 120	CC 102	561
Low Load Forecast	Coal Available in 2002	1614748	0	-	-	-	-	GT 33	-	C 120	-	-	2xGT 33	C 120	339
High Load Forecast	Coal Available in 2002	2341963	0	-	-	2xGT 33	C 120	C 120		C 120	2xGT 33	C 120	CC 102	C120,GT	867

Expansion candidates:

C 120	Pulverized coal (120 MW)
CC 102	Combined cycle (102 MW)
GT 33	Combustion turbine (33 MW)

Other candidates (not selected into the expansion plan until 2009) included: oil-fired steam turbine (63 MW), pulverized coal (80 MW), medium-speed diesel (20 MW), low-speed diesel (30 MW), one storage-type hydro project (Back Rio Grande 50.5 MW), and seven small run-of-river hydro projects (less than 10 MW).

Notes: (1) Cost of Plan = Present worth (in U.S. dollars as of 1997) of the total operating and investment costs over the study period 1997-2017.
(2) For the scenario “No GT in 2001” the reliability constraints in 2001 were relaxed to enable a feasible solution.

- In the January 1999 report the planning period was defined from 1999 to 2009. The least-cost expansion plan obtained for the base case analysis calls for the commissioning of 33 MW combustion turbines in 2001, 2004, and 2007, 120 MW pulverized coal units in 2002, 2005, and 2008, and a 102 MW combined cycle unit in 2009. Both the combustion turbine and combined cycle units were assumed to be using automotive diesel oil (ADO) fuel. In addition, for the base case analysis it was assumed that the 120 MW coal-fired unit would be available for commissioning in 2002.

- There are certain reservations with regard to the availability of a coal-fired unit in 2002. Based on the experience of many utilities around the world, the average construction lead time for coal-fired generating units is usually 3-5 years. In the case of Jamaica, the construction of a coal-fired unit would also represent an introduction of a new generating technology into the system. As coal has to be imported, this would also require a construction of appropriate coal handling facilities. In addition, there is a need for plant site preparation, which may take from 6 months to 1 year. These are the main reasons why two sensitivity studies were carried out to investigate what would be the least-cost expansion plan if the coal-fired candidate unit was not available for commissioning in 2002 but in 2003 and in the other case in 2004. In both cases, the coal-fired generating unit remained a part of the least-cost solution and was selected into the expansion plan in the first year in which it was assumed to be available, in 2003 and 2004, respectively. The need for new generating capacity in the years before the coal-fired unit becomes available for service was satisfied by adding 33 MW combustion turbines. The delay of coal-fired unit until 2003 caused an increase in the present value of the total system expansion cost of U.S.$ 457,000 compared to the base case analysis. A delay of the coal-fired unit until 2004 caused a more significant cost increase of U.S.$ 2.161 million.

- The least-cost optimization of system development was also performed for a scenario assuming that there will be no construction of coal-fired generating units. This was the so-called "no coal option." The least-cost solution obtained for this scenario calls for the commissioning of 33 MW combustion turbines in 2001, 2002, 2005, and 2007, and for 102 MW combined cycle units in 2003, 2006, 2008, and 2009. The total capacity of new additions in the period 2001-2009 is 540 MW, which is lower than the addition of 561 MW in the base case analysis. However, the total system expansion cost (1997-2017) for this scenario is U.S.$ 28.2 million higher than in the base case analysis.

- Another sensitivity analysis was performed to determine the effects if no combustion turbine will be commissioned in 2001. For this case, the LOLP constraint had to be relaxed in 2001 in order to allow the optimization program to reach a feasible solution. The LOLP in 2001 for this case amounted to 0.912% which is higher than the LOLP goal of 0.55% (2 days per year) adopted by JPSCo. For reference, in the base case analysis, the LOLP in 2001 amounts to 0.275% because of the addition of a 33 MW combustion turbine. Overall, the total cost of this expansion scenario is about U.S.$ 1.369 million lower than that of the base case expansion plan. The combustion turbine that was in this scenario blocked from commissioning in 2001 was selected by the optimization program in 2003. Also, the energy-not-served costs in 2001 were higher than in the base case analysis and this partially offset the savings made by postponing the construction of the combustion turbine by 2 years.

- To determine the influence of forced outage rates of generating units on the least-cost expansion plan, a sensitivity analysis was conducted in which forced outage rates of all candidate units were set at 5%. The optimization results showed that coal-fired candidate units were slightly more preferable for system expansion than in the base case analysis in which their forced outage rate was specified as 8%. The changes in the expansion schedule were minimal and mostly in the later part of the study period. Compared to the base case, the first change in the expansion schedule occurred in 2009 when a 102 MW combined cycle unit replaced a 120 MW coal-fired unit. Compared to the base case analysis, the cost reduction of U.S.$18.167 million over the study period 1997-2017 demonstrates the importance of lower forced outage rates for candidate generating units.

- The new base case analysis was conducted as an economic comparison of different system development options without local taxes and duties imposed on any of the energy sources. A sensitivity analysis was performed with the 40% tax imposed on the diesel oil. The results showed that combustion turbines because of their relatively low capacity factor were not affected by this tax as much as the combined cycle units. The combustion turbine units remained in the least-cost expansion schedule that was obtained for this scenario, while the coal-fired generating units replaced most of the combined cycle units.

- A number of sensitivity studies were carried out to examine possible effects of an increase in capital investment costs of the 120 MW coal-fired candidate units. For an increase of net overnight costs between 1% and 3%, there was no change in the least-cost expansion schedule and the first coal-fired unit was selected for service in 2002. For a cost increase from 4% to 8%, the coal-fired unit was pushed back by one year and selected for service in 2003. An increase in capital costs of 9% or higher pushed the commissioning of the first coal-fired unit into 2006 and later. The sensitivity study presented in Table 3 shows the results obtained for the scenario that assumed that additional infrastructure costs for coal handling facilities were added to the capital costs of the first generating unit. In this case, the coal-fired generating unit was not selected into the least-cost expansion plan during the planning period until 2009.

- Sensitivity studies were also performed to determine possible effects of the increase in coal prices. In these studies the coal prices were increased by a certain percentage in the base year while retaining the same escalation factors as in the base case over the study period. For an increase in coal prices between 1% and 5%, there was no change in the least-cost schedule and the first 120 MW coal-fired unit was selected in 2002. For a coal price increase between 6% and 15%, the coal-fired unit was pushed back by one year and selected for service in 2003. The optimization results for the sensitivity analysis that are presented in Table 3 are for the case assuming a 10% increase in coal prices.

- The optimization of electric system development was also performed for the low and high load forecasts. In the case of low load forecast, the least-cost expansion plan consisted of a 33 MW combustion turbine in 2003, followed by a 120 MW coal-fired unit in 2005. For the

3 CONCLUSIONS AND RECOMMENDATIONS

- Based on the results of system simulation and optimization of system development there will be a need for additional generating capacity in 2001 if the reliability goal for system operation (LOLP of 0.55% or 2 days per year) is to be maintained. This capacity would be in addition to the existing JPSCo program for restoring and increasing the capacity of existing generating units (estimated capacity increase in 2001 is about 20 MW) which is already taken into account in the base case analysis. This issue was extensively discussed with JPSCo experts who indicated that two additional possibilities exist for achieving an increase in system reliability in 2001. One is a comprehensive preventive maintenance program that would bring the overall availability of the generating system to above 90% (this program started in 1998 and has already achieved some encouraging results), and the other by restoring the capacity from two existing gas turbines that are currently not in use. Argonne experts agree that both activities would contribute to the increased reliability of system operation. However, additional studies should be carried out to determine if these actions would be sufficient to achieve the desired reliability level of system operation in 2001.

- The 120 MW coal-fired generating unit appears in the least-cost solution for the base case analysis and most sensitivity studies. Two sensitivity studies dealt with Argonne concerns regarding the earliest possible startup date for this technology. In these studies the first available year for the introduction of coal-fired generating units was delayed from 2002 until 2003 and 2004, respectively. In both cases the 120 MW coal-fired unit was selected into the least-cost solution in the first year in which it was considered available. The commissioning of additional 33 MW combustion turbines satisfied capacity needs in the years before the introduction of coal-fired units.

- The issue of possible slippage in the implementation schedule also needs to be addressed. Slip results from both poor schedule estimating and uncertainties in project implementation. The World Bank conducted an analysis of schedule performance by examining a total of 61 thermal power projects approved for financing in developing countries between 1965 and 1986. The main causes of slippage in project implementation schedule were grouped into three categories by attribution of responsibility: (1) project client and engineers, (2) contractors and suppliers, and (3) uncontrollable events. The study found that the relative frequency of causes in these three categories were as follows: client/engineer – 34%, contractor/supplier - 50%, and uncontrollable events - 16%. A wide range of causes were cited, and they are listed in Annex 1. The relative importance of the causes were identified by counting the number of times that each cause was cited in project completion reports.

- The other concern regarding the introduction of 120 MW coal fired unit is connected with its performance in the relatively small generating system of Jamaica and its possible impact on the reliability of system operation. This issue has also been discussed extensively with JPSCo experts who were rather confident that the introduction of a large unit of this size would not adversely affect the operation of the system. The discussion covered the issues of “must run” capacities and minimum system load, maintenance scheduling, forced outages, stability of the transmission network, etc. JPSCo experts pointed out that they have in place an under-frequency load shedding plan that comes into effect in case of large forced outages. According to JPSCo experts, in one instance the system has survived a simultaneous outage of two 68 MW generating units. Argonne’s recommendation to JPSCo is to perform additional analyses of system operation with the 120 MW coal-fired units using a detailed production cost model, as well as to perform load flow and stability analyses of the transmission network.

- The siting and environmental studies for the potential location of the coal-fired power plant should be accelerated and completed as soon as possible. One of the important considerations should be to choose a site that is capable of accommodating multiple generating units.

- The environmental issues concerning the coal-fired technology for electricity generation should be discussed publicly. There are numerous “clean coal technologies” and environmental control technologies presently available that are capable of significantly reducing the emissions from coal-fired power plants. For example, electrostatic precipitators are capable of reducing 99.5% of particulate emissions, while flue gas desulfurization equipment can reduce SO_2 emissions by more than 95%. The general public in Jamaica should be informed in an easy to understand manner what control technologies would be installed at the coal-fired power plant and what their efficiency would be in pollution mitigation. This is especially important because of the possible repercussions on the tourist industry.

- The levelized electricity production cost from the 120 MW coal-fired generating units is lower than that of the oil- and diesel-fired candidates. The sensitivity studies on coal prices showed that coal-fired generating units would remain competitive in case of coal price increases up to 15%.

- The results of the sensitivity studies showed that the 120 MW coal-fired candidate units are rather sensitive to an increase in capital investment costs. The base case analysis assumed for the 120 MW coal-fired generating unit a net overnight cost of U.S.$ 1,300 per kW of capacity, which was increased by 15% to U.S.$ 1,495 per kW to account for the environmental control equipment. Sensitivity studies showed that a 4% increase in capital costs would delay the coal-fired generating unit by one year to 2003, while a 9% increase would postpone its commissioning until 2006.

- The 102 MW combined cycle and 63 MW oil-fired steam candidate units were less desirable for baseload duty than the 120 MW coal-fired units mostly because of the higher fuel costs. The heavy fuel oil for oil-fired candidate units was about 45% more expensive than the coal in the base year, while the combined cycle units were modeled as running on expensive automotive diesel oil. The other coal-fired candidate unit (80 MW) was less competitive than the 120 MW unit size because of lower efficiency and higher specific investment costs.

- The possible use of liquefied natural gas (LNG) as a fuel for the combined cycle candidate units was discussed in the January 1999 report. The authors correctly concluded that the price of the LNG fuel in combination with the high infrastructure cost for the construction of an LNG terminal does not make LNG-fired combined cycle units very competitive in the near term. This is especially true considering the potential capacity need of the electric sector for just a few relatively small combined cycle units during the planning period until 2009. However, the construction of an LNG terminal may be justified if the needs of the whole energy sector in Jamaica are considered, especially in the long term. In this case, the LNG-based combined cycle units could also become more competitive for the expansion of the electric sector if a part of the infrastructure costs for the LNG terminal are spread over other industrial users. This issue needs to be carefully studied in context of developing a national energy strategy for Jamaica.

ANNEX 1

Factors Responsible for Schedule Slip in Thermal Power Projects

Client/Engineer

- legal requirements/bureaucratic procedure for awarding contracts
- initial schedule was too optimistic
- bid evaluation difficulties
- delays in procurement/placement of orders
- change in project scope
- modifications to major equipment required
- disagreement between Bank and borrower over contract award
- site change

Contractor/Supplier

- labor disputes/strikes in manufacturer's country
- labor disputes/strikes in project country
- shipping delays
- substandard work had to be redone
- equipment failure during testing
- skilled labor shortage
- manufacturing difficulties
- shortage of materials
- contractor inefficiency/lack of coordination
- technical problems with equipment
- contractor bankruptcy
- transportation difficulties

Uncontrollable Events

- damage/need to redesign civil works due to earthquake or other natural disaster
- unusually bad weather
- accident – damage to equipment
- political turmoil/coup/invasion
- civil disturbance